Net Metering Task Force
Focus Group Interview Questions
Written Responses of National Grid
January 26, 2015

<u>Executive Summary</u>

National Grid appreciates the opportunity to provide these written comments. We are fully supportive of the 1600 MW solar photovoltaic (PV) goal by 2020. While this is an aggressive goal, we are confident that the Commonwealth will achieve it. Importantly, we believe that the Commonwealth can achieve it in a more cost effective way than our current structure allows.

Net metering, which may have been appropriate to jump start this important market, is not sustainable in the long run. Indeed, if Massachusetts were ever to achieve wide-scale solar deployment, with solar panels on every roof, with all customers net metering, there would be no one left to pay for the distribution system on which all of those customers would still rely for services, whether the solar facility was generating or not. This shows how important it is to develop the right long-term, sustainable construct, so that we can benefit from solar PV and other renewables without creating new problems.

In particular, National Grid notes that a virtual net metering (VNM) facility, where a customer is generating electricity in one location and applying net metering credits at an altogether different location, is far removed from the original concept of net metering, which was to allow the netting of behind the meter generation from the usage at that same location. As a result of the current net metering rate design, VNM systems result in a much higher cost to distribution company customers than if the generation were behind the meter.

Solar is also supported through additional incentive payments for solar renewable energy credits (SRECs), which have been provided regulatory price supports that have been higher than needed to build solar, and far more than being paid in other states for similar incentives. Plus, the instability of the value of solar renewable energy credits (SRECs) imposes higher costs on owners of solar installations than other support mechanisms, as they are unable to borrow as much to fund the development of the installations from financial institutions that value a stable source of revenue. As a proven, low-risk, and predictable generation resource, solar PV should be paid for with a low-risk revenue stream, to reduce the cost of financing as much as possible.

The right incentive program will enable the development of a resource like solar PV at the lowest cost to non-participants, paying no more subsidies than are necessary in a transparent, simple and administratively efficient way. The use of standard performance-based incentives, publicly set ceiling prices, competitive processes for larger systems, and tariff-based payments could together create the right solar support mechanism to achieve the stated goals.

1. Stakeholder objectives and priorities from the Task Force process

What are your goals and objectives for the task force? Of those, what is your most important objective and why? To the extent that goals or objectives may conflict, how would you prioritize?

National Grid's main goal for the net metering task force is to develop agreement on a sustainable future for renewable energy generation in an integrated distribution grid. A sustainable future is one where the renewable programs are: (1) delivered at least cost to customers; (2) easily administered; (3) supported by appropriate cost recovery from all customers, including those with renewable energy generation, for the services they are receiving from the grid; and (4) provided in a transparent, competitive, and cost effective manner that considers all incentives available. At present, Massachusetts is paying more for solar energy than its neighbors, and this is unnecessary and unfair to those footing the bill.

2. Long-term Massachusetts solar market goals

The current stated goal of the Massachusetts solar policies is to reach 1,600 MW of installed solar capacity in the 2020 timeframe. Please discuss your perspective on this MW goal, its timing, and the appropriate objectives for the state solar market beyond the timing and quantity of this goal.

National Grid views the 1600 megawatt (MW) by 2020 goal as an aggressive, but achievable goal. The 1600 MW target will provide about of 4% total energy supply and represents 14% of historic peak demand as measured for net metering purposes in Massachusetts. The goal is aggressive in light of the industry development needed to install this amount of solar, the changes required at utilities to interconnect and manage this amount of solar, the complex customer management for both developers and utilities that is part of that expansion, and the overall cost of the investment in solar, estimated in the range of $5 billion to $6 billion.

National Grid supports the timeframe for reaching the goal. However, as with the first phase of the Solar Carve-Out certificate program (SREC I), which sought to develop 400 MW by 2017, we believe this goal will also be met earlier than expected because of the high incentives provided to solar owners in the combination of net metering and SRECs, along with the current allowance of VNM. The regulatory construct for VNM is allowing developers to choose low cost locations, receive very high value for their output, and use the distribution system for free to deliver their product to their credit purchasers.

National Grid feels strongly that transitioning to minimum bills, and potentially to a more disaggregated rate design, as described in the answer to Question 6, could better align the value and benefits provided and received by all solar PV, to create a more sustainable future for the use of this important resource, and still make the goal within the 2020 timeframe. Moreover, changes in solar policy overall are needed to lower the total cost of the Solar Carve Out program, or any successor to it, and reduce the cross-subsidies associated with net metering, so that more net benefits (or a smaller net cost, if benefits are less than total costs) are enjoyed by all of the state's residents. This would also have the beneficial effects of reducing payments to solar developers and their investors, whose beneficiaries are largely out of state, and keep a larger proportion of the benefits of solar development for the citizens of the Commonwealth.

3. Perspectives on current net metering approach

Solar PV systems in Massachusetts typically benefit from net metering with various system sizes and configurations receiving different net metering benefits. Additionally, volumetric caps to net metering have been revised through legislation on multiple occasions over the past several years. Please provide your perspective on the current Massachusetts net metering approach.

In discussing the value of net metering credits, the above statement appears incorrect. In Massachusetts, most of the large net metered systems receive the same value of credits (albeit in greater amounts) as the smallest net metering systems, because a customer's rate class is presently assigned on the basis of on-site usage, rather than the volume of energy exported or connection size. Furthermore, net metered systems that are coincident with load receive the same value of credits as those that are not coincident with load. This means that a customer who could establish a solar facility to actually serve some portion of its load has a disincentive to do so, if it would be more remunerative to separately meter as a VNM system.

These details highlight how net metering may have been an acceptable way to "jump start" an important market, but is inappropriate for the long term and should be changed now. Customers who net meter can, with enough output or credits, avoid paying for the services they are receiving from the distribution utility, which include: (1) delivery of excess output; (2) provision of voltage; (3) system stability; (4) delivering instantaneous power requirements in excess of generation capability; and (5) backup power when self-generation is unavailable. If all of National Grid's customers were to put solar on their roofs and net meter, no one would be paying for the distribution system that they are all using for these services,. This highlights the inherent flaw with net metering and why we must find an alternative if we want to have a sustainable renewable energy future.

The amount of the net metering credit, based on the sum of distribution and commodity prices, is divorced from the reality of any benefit these facilities are providing. This is especially true in Massachusetts which also provides considerable value for a solar array's unique, renewable attributes through solar renewable energy certificate (SREC) support. Furthermore, customers who do not partake in solar development and net metering are picking up these costs, placing an unfair burden on them.

As explained above, a key net metering benefit in Massachusetts is VNM, a tool that promotes renewable generation by allowing a customer to generate electricity in one location and capture credits a high volumetric rate, and then apply those credits to at a location that is taking electric service at a less-volumetric rate. As such, the current rules create a type of "arbitrage," which incentivizes customers and developers to maximize revenue by locating a generating facility as a separate account in a separate location instead of behind the customer's load and meter. This is far removed from the original concept of net metering, which was to allow the netting of behind-the-meter generation from the usage at that same location. VNM also results in a much higher cost to distribution company customers largely due to the way the energy is sold at the generation site for wholesale value to the ISO-NE, while the receiving account is still served as a full-requirements load. National Grid's analysis shows that VNM facilities cost our customers more than behind-the-meter facilities that offset a customer's electricity load in "real time." Using rates now in effect, it will cost all of our customers approximately $70 million dollars per year to subsidize a nine percent net metering cap that consists of VNM facilities, compared to approximately $40 million per year if all facilities were behind the meter, approximately 75 percent more.

Thus, a customer is given a powerful incentive to install a VNM facility instead of a behind-the-meter facility, and no incentive to reduce actual electricity load. Essentially, this is an accounting construct that promotes the development of renewable energy projects and allows a minority of customers to avoid all cost responsibility for supporting the distribution system on which they rely.

4. Perspectives on current Massachusetts solar incentive model approach

Massachusetts solar installations typically benefit from a range of incentives, including SRECs, federal tax credits and net metering being major contributors to system economics. Please discuss your perspective on the current mix of incentives other than net metering (and virtual net metering) available to Massachusetts solar systems with a particular focus on the Massachusetts SREC incentive.

The Solar Carve-out within the Massachusetts RPS creates demand for SRECs, the design of which has posed a much higher cost on all customers than was needed for the development of solar PV. In addition, the instability of the value of SRECs imposes higher costs on owners of solar installations than other support mechanisms, as they are unable to borrow as much to fund the development of the installations from financial institutions that value a stable source of revenue. As a proven, low-risk, and predictable generation resource, solar PV should be paid for with a low-risk revenue stream, to reduce the cost of financing as much as possible.

The Solar Carve-out design has several elements that resulted in the high cost approach. This is especially true for the SREC I program. First, the maximum value for SRECs, determined by the SREC Alternative Compliance Payment schedule, was administratively set at a time when solar PV cost much more to install. It was then insensitive to rapidly declining costs, and remained insensitive during periods of shortages of SRECs. This critique also applies to the Solar REC Clearinghouse Auction price in the regulations, which was set at $300 and has not been altered. The SREC II program improved on these elements by creating a lower and declining ACP and auction price schedule. In addition, the new program introduced the SREC factoring approach, whereby a MWH generated is multiplied by a percentage to determine how many SRECs that hour of generation has produced. This had helped bring the costs of Phase II of the Carve-out program down compared with Phase I on a per MWH basis.

However, the SREC program as a whole is still higher in cost than other options, even under SREC II. Competition based on price for total production value by the developer/owners of mid-sized and larger solar facilities would likely push the total cost of solar subsidies down to half of the current level. This pricing level has been seen in other states that have used competitive programs, which will be detailed further in the answer to Question 5. In addition, SRECs and net metering credits are not linked in Massachusetts in a total value. This means that when SREC costs and energy costs are both high – such as the current period – the amount being paid in total to existing systems is very high. By contrast, a fixed price allows the SREC, or incentive, portion of the payment to shrink as the per kWh value of delivered energy rises.

In short, the SREC structure of the Solar Carve-out established a high-cost, high-risk policy support mechanism that was designed to induce a surge in investment activity, which was then difficult and slow to revise when solar development costs declined sharply. While improved upon in Phase II, the program uses a higher cost and higher risk approach than a support mechanism that would use competitively-set fixed amounts for total solar PV production. We believe the SREC approach, like net metering, is unsustainable and results in unnecessary costs to electric customers as a whole.

5. Perspectives on other solar incentive models

Other states have implemented a range of incentive program types in order to grow their solar markets. Several program types that you may be aware of include (but are not limited to):

- ***Standard offer incentive programs (aka. feed-in tariffs)***
- ***Declining block incentive programs***
- ***Competitive procurements (aka. auctions or solicitations)***

There are also many variations on these approaches, as well as co-policies.

Are any of these incentive program types of particular interest to you? Please discuss your impressions of these or other incentive program types that you may be aware of, and whether we should focus on particular incentive types that are of interest to you. How do you think the effectiveness of these incentive program types vary for different solar installation types (e.g. residential vs. utility scale)? What options would you like to see the consulting team consider and analyze for Massachusetts?

We believe the best solar incentive program is one that enables the development of a resource like solar PV at the lowest cost to non-participants, and creates a sustainable solar industry, with low or no subsidies, that can deliver further installations of solar after the 1600 MW goal has been reached. In summary, the use of standard performance-based incentives, publicly set ceiling prices, competitive processes for larger systems, and tariff-based payments all enhance the cost-effectiveness, transparency, simplicity, and risk reduction of a solar support mechanism.

This year, National Grid expects to have the Renewable Energy Growth program (RE Growth) available to Rhode Island customers who are interested in hosting solar PV or other renewable energy resources. This program will include some of the approaches mentioned above, and it will cost all customers nearly half, on a levelized per megawatt-hour basis over 15 years, as much as the combined cost of the Massachusetts net metering and SREC II programs.

The program combines several elements that make it attractive to the Company, participants, and non-participants. First, it is a tariff-based program, in that all of the payments for solar output will be secured and governed by a public utilities commission-approved tariff, and it does not involve contracts, market transactions, or auctions. For small and medium sized solar PV facilities, up to 250 kW in DC nameplate capacity, there will be a fixed price tariff, or Standard Performance Based Incentive (PBI), that varies by system size and ownership.

In exchange for all energy, capacity and RECs, non-residential customers will receive a fixed payment per kWh generated for 20 years (as proposed). Residential customers will receive bill credits for energy (up to their monthly usage) and sell their RECs for the remainder of the PBI amount. The Standard PBI prices are established annually through a public process run by the Rhode Island Distributed Generation Board that must take account of estimated system costs, a reasonable rate of return, and the results of competitive solicitations for such support by larger system owners. This mechanism is simple and low risk, and provides transparency to all customers about how much is being paid for solar output.

National Grid believes the use of the Standard PBI for smaller systems is appropriate along with the regular and public review of the price being paid, with approval from the state's utility regulators.

Solar systems greater than 250 kW, along with other renewable resources, must submit bids in response to competitive solicitations, which are capped by a ceiling price that is established every year by the same RI Distributed Generation Board. Projects will be selected on the basis of price until each enrollment is full, thereby enabling all customers to pay the lowest overall cost for the renewable energy resources. Pursuant to a tariff, the projects receive payments for their output as bid.

National Grid and stakeholders developed this program based on our experience with the Distributed Generation Standard Contract (DGSC) program, which had a 40 MW goal for renewable resources and procured 37 MW. The last procurement of the DGSC enrolled solar PV systems ranging from 173 kW up to 1.25 MW. The total costs for the output from this program, which involved 15-year contracts, ranged from $150 to $240 per MWH, with most systems receiving an average of approximately $200 per MWH. This is approximately half of what similar sized systems will receive, on average, over a similar period in Massachusetts, on a levelized basis.

New York has also used a competitive process that combines upfront grant and short-term performance incentives to solar PV projects greater than 200 kW in size. Under the program, winning proposals received more than $1100 per kW at first in 2011, declining to an average of $439 per kW in the most recent solicitation. An award of $439 per kW is worth an equivalent of $58 per MWH over a period of 10 years, assuming a 10% discount rate. However, this subsidy is provided independently of any revenue captured through net metering, direct on-site usage, or the sale of energy to the NYISO. For this reason, the program does not protect all of the customers who will fund it from any increase in energy and net metering costs, and it continues relying upon the cross-subsidies embedded in net metering, as described in the response to Question 3.

New York is currently in transition to a "declining block" program for solar PV (an approach that was outlined in Massachusetts bill H.4185). A declining block program sets an initial level of subsidy support based on some analysis of the current costs and returns needed to develop a facility. As a "block" or measured amount of capacity is enrolled, the value for the next block steps down to a lower value. Thus, the initial block might receive a total of $250 per MWh, and the second block may receive $230 per MWh. The block values would decline to some predetermined end-point when the program is fully enrolled. While simple and predictable, this mechanism is less cost-effective than a competitive model, and is also insensitive to declines or increases in costs. The support offered by such a program does not take into account the varied development costs and return expectations of different facilities and owners, which can better be met through a competitively set tariff. It does, however, provide open access to the support mechanism and a known cost to all customers, thereby enhancing its transparency. But given the enormous burden created by the SREC program, National Grid would strongly favor a competitive program over a declining block design.

6. Perspectives on future use of net metering, as well as minimum bill provisions

During the past year, efforts have been made to revise the framework for net metering in Massachusetts including the addition of a minimum bill for all electricity ratepayers. Please discuss your perspective on the future use of net metering/virtual in Massachusetts and, to the extent you are able, what options or changes would you like to see and why?

Net metering will not provide a sustainable future or enable the healthy growth of renewable energy generation because net metering customers are avoiding their fair share of system costs, and the costs for non-participants will continue to rise, creating a further demand for net metering as a way to avoid high costs. Taken to its logical conclusion, there would be no one left to provide the subsidies everyone would be receiving. In the long term, this will lead to stranded costs and financial instability for distribution utilities. Only a financially sound distribution company can integrate large amounts of distributed generation. Once interconnected, the distribution company must accept generation from the customer, manage the voltage requirements of the generating facility, manage the voltage levels and frequency levels required for a stable grid, serve instantaneous demand whenever the customer's load exceeds his or her generating capability, and serve the customer whenever his or her generating facility is not producing electricity. According to the Electric Power Research Institute, in order to accomplish all of these tasks independently of the grid, a customer would need to invest between four and eight times more money into their system.[1]

Also, net metering does not send appropriate price signals for customers to consider different operating criteria that may improve the efficiency of the overall electric grid. Under net metering, customers maximize their financial benefit by producing as many kilowatt-hours as possible. Usually, this would promote an installation that faces directly south for solar PV systems, which produce peak output earlier than at the typical system-wide or feeder level peak demand. At present, net metering does not incorporate price signals to promote more efficient behavior or alternatively, provide a credit for services to the utility. National Grid recommends that net metering, or its successor design, should be crafted so as to reward solar PV generating customers to install advanced inverter technology or turn their system to the west to help meet system peak load needs, as services to the utility, and not reward those system owners who choose not to provide those services.

Virtual net metering only amplifies the cost recovery problem. A solar developer can allocate kWh to an account far away without paying any delivery charges. At the same time, the customer who receives the kWh value receives a lower bill. However, neither party is paying an appropriate share of the fixed costs of the distribution system. Virtual net metering can only happen with connection to the grid. For that reason, both the generating customer and receiving customers should be paying a fair share of the costs to create an integrated grid.

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[1] Electric Power Research institute, "The Integrated Grid: 2014, p. 7, and pp 16-23 along with Appendix A for discussion of services and cost estimates.

In the long term, National Grid believes these inequities should be solved with a rate design that derives from a several basic concepts:

1) Customers using energy and distribution system services should pay for those services in a fair manner, including coverage of the fixed costs of the T&D system;
2) Customers with generation should be able to use their generation on-site, and should be compensated for generation put on the grid in a fair manner, as well as pay for access to the grid with coverage of an equitable share of the fixed costs of the T&D system;
3) Customers that provide services to the grid should be compensated for them; and
4) Additional incentives the Commonwealth would like to provide to a technology, like SRECs, should provide all other remuneration and should be equitably funded by all electricity customers in the state who can receive them.
5) Such rates should be set through proceedings at the Department of Public Utilities.

As a first step toward that model, National Grid believes a minimum bill will allow for more appropriate cost recovery from all customers. Minimum bills should be designed to recover distribution costs of service based upon causation, i.e. size of customer and diversity of customers contributing to the calculation of the minimum bill. Also, minimum bills could be designed to recover non-distribution costs that are impacted by reductions in kWh deliveries such as costs for systems benefits (energy efficiency programs, renewable programs, low income credits, etc.).

The minimum bill should be based upon the size of the customer since the system is designed to serve their maximum loads. Small customers with lesser need for the system should not pay the same amount for a minimum bill as much larger customers. (This approach is standard for demand-based rates where the rate per demand is the same but the amount of a customer's bill is dependent on the size of its demand.) For smaller customer sizes, minimum bills could be based on service connection level, total monthly usage (inflow or outflow of kWh), or an actual measure of peak use with eventual deployment of Advanced Meter Functionality. For larger customers, the tools are already in place to measure peak kW and kVA, and minimum bills can be designed to reflect the maximum export or import by the customer at its location.

This approach would have other beneficial effects, beyond more equitable cost allocation. Customers will be incented to save by managing their maximum demand on the grid, which may reduce growth related distribution upgrade costs, transmission capacity costs, and regional increases in generation capacity needs. This could be accomplished by lowering on-site peak demand and/or managing generation capability to ensure output is available at peak demand times. This design would also provide an appropriate charge to customers that are primarily generators that transmit their output onto the distribution system and sell energy to other customers at remote locations, as most VNM customer hosts are doing today.

Finally, the design could allow for minimum bills to be reduced through the provision of measurable services to the distribution company at prices that reflect the value of the services to the distribution grid. Such services might include peak reduction in an area with identified constraints and/or voltage optimization at the feeder level.

The specifics of the minimum bill, as with all rate design, would be determined in the context of a distribution company's rate case before the Department of Public Utilities.

7. Perspectives on policy transitions

A. At the 2nd Task Force meeting, it was suggested that analysis should account for uncertainty costs, (i.e., transition costs due to changing goals and programs.) Please discuss qualitatively the nature of these costs as you see them, and whether and how you might suggest such costs could or should be quantified.

National Grid is uncertain regarding the meaning of this question. Every stakeholder faces uncertainty in regular times and during transitions. For example, a transition from net metering to another form of compensation for customer generation will create uncertainty for the generating customer but create benefits for other customers in the form of reduced costs from an improvement in the equity of cost recovery among customers for distribution services. Thus, any uncertainty in costs by one stakeholder will result in opposite benefits for other customers. These uncertainties cannot be considered simply a cost but the result of improving the fairness and equity of cost recovery as well as helping to lower overall costs to customers.

The appropriate means to deal with uncertainty is to create as much certainty as possible regarding a transition. Important elements such as start date, end date, length of transition, goal of the transition, major milestones and approval dates will help everyone adjust to the purpose of the transition and prepare for the changes ahead. Uncertainty is created when goals, purpose and timeline are not clear or are subject to extension, modification or delay. Once these are made clear, uncertainty costs can be minimized or avoided as stakeholders adapt to the schedule, purpose and goal of the transition.

B. Are there particular threshold milestones where it might make sense to consider policy transitions in order to minimize such costs? What other means are available to minimize such costs?

Every effort should be made to minimize costs to utility customers. Transitions should be designed to accomplish their benefit for customers quickly and milestones should be selected in accordance with the goal. Competitive acquisition of resources necessary to implement policy is one means to minimize transition costs since, by definition, the bidders have provided their best price for the service. Transitions defined by competitive solicitation will minimize any perceived transition costs by stakeholders while providing maximum benefits for customers.

8. Sector-specific topics

1. Group A: Utilities

How would you propose a minimum bill calculation methodology be applied? What other models would you point to that are viable for achieving your objectives?

As discussed in the answer to Question 6 above, all customers, both load and generation, should be charged a minimum bill based upon size as measured in demand/maximum output capability or energy use/energy produced. The minimum bill calculation should be applied according to a customer's size as measured by their actual maximum demands or by alternatives to measuring demand when demand meters are not available. Alternatives to measuring demand include customer charges based upon a range of kWh use or the service size of a customer's home or business, if available. Using measures of demand in kW or kWh ranges encourages customers to manage their use to improve system efficiency and lower their costs as well as costs on the grid. Customers would also still have the incentive to consider energy efficiency measures that not only save energy but save on maximum demand to effect an improvement in the capacity utilization of the grid. Improved utilization of the grid will lessen the need for future investment and lower the average cost to customers as utilization increases.

Other models include raising the customer charge. This option has been proposed and approved in a number of jurisdictions as a simpler means to put in place a minimum bill structure. One drawback to the approach is the disconnection from improving customer efficiency and system efficiency as more costs are moved to a charge that does not have any variation. Another drawback is the disproportionate effect on smaller customers from increases in the customer charge. Finally, this approach may take longer to effect a transition since bill impacts to all customers must be considered and a one size fits all customer charge will take longer to finalize to a point in which it recovers the amount of non-bypassable costs necessary to run a distribution grid.

The best design in the end would be one where all customers accessing and using services from the grid pay an appropriate share of fixed costs of the grid, and those providing grid services are compensated for them. This is a step beyond net metering, towards a more realistic assessment of cost responsibility and value of services provided.

With respect to FCM revenues for current Class II and III systems, for which utilities secure certain rights under net metering tariffs, please describe your current practices, and future plans.

The enrollment of solar PV capacity from net metering systems is currently under consideration by National Grid.

Are utility system integration costs for solar projects now fully borne by project owners?

Costs to interconnect a project with the distribution system are borne by interconnecting customers. However, there are operating and maintenance (O&M) expenses of new infrastructure that are not included in rates or borne by the customer. Under the current interconnection tariff, on-going O&M costs are not being collected from the DG customers when they pay for a system upgrade to allow their project to interconnect with the electric system. With an approximate 6% annual O&M cost, every dollar paid for an upgrade results in 6¢ of on-going annual O&M costs (maintaining the equipment, tree trimming, local property taxes, etc.). In 2013, the Company built approximately $15 million in interconnection upgrades (primarily in rural areas with minimal existing electric load), which results in on-going annual O&M expenses of approximately $900,000 that are not being collected from the interconnecting customers and are not reflected in base rates.

Residential customers are rarely charged any money to interconnect, and the Company has installed over 8,000 residential class net meters over the past four years. At approximately $75 per meter, this is an additional $600,000 of capital investment that will not be included in rates until the next general rate case. The current rate of residential solar installations is about 7,500 per year, so the Company expects an additional $560,000 per year of such investment, along with the associated annual O&M costs as described above.

What are the expected potential impacts of Grid Modernization/Time-Varying Rates efforts on net metering value and framework?

In the recent docket on Time Varying Rates, the Department determined that TVRs were appropriate for charging the costs of Basic Service. However, the Department accepted the argument that the costs for distribution service would be recovered through different means, not necessarily TVRs. If in service, customers could receive the value of the time varying rates when their generation is running. However, there are many issues with this approach that have not been examined, all relating to reconciliation of costs and cost incurrence in the ISO-NE market. National Grid is using its Smart Grid Solutions pilot in Worcester to examine these issues as some pilot customers do have solar generation behind the meter. The introduction of TVRs at the retail level that differ from the prices charged in the wholesale market introduces risks to cost recovery and efficiency that must be understood before any impact can be estimated. Thus, the potential impacts are unknown at this time.

Grid modernization can have a tremendous impact on customer investment in distributed generation, particularly when costs are recovered appropriately through minimum bill provisions. Grid modernization investments can prepare the grid for widespread use of distributed generation by creating the means to integrate the generation into the distribution grid. However, this can only happen with appropriate pricing for distribution services that appropriately funds those investments that prepare the grid for DG by charging generating customers appropriately for costs incurred.

What are your experiences in other state solar markets with alternative incentive models or policies in place?

Please see the answer to Question 5 above.

Please describe your past and expected future participation in SREC floor price auctions.

National Grid has not participated in any of the SREC auctions, but this is open to review and determination as each auction arises. National Grid has not participated because (1) the Company has generally been in the marketplace for SRECs prior to and during the auction and has typically secured sufficient SRECs at a cost lower than the auction floor price of $300 to match with its compliance obligation, and (2) purchasing SRECs in the auction would be speculative if meant to be used for load that is not near term (from the current year to 18 months in the future), and would require the company to fund the purchase well before such costs could be collected in commodity rates. However, if the Company needed SRECs for the current year at the time of the auction, and market prices were above the auction floor price, then the Company would consider participating in the auction in order to reduce overall RPS costs for customers.

What information can you make available to the consulting team to help us assess the role of avoided T&D cost (if/where applicable) and avoided distribution losses resulting from installation of distributed solar generation?

The Company is comfortable with using the 2007 Navigant study as a starting point. This study focused on specific deferral opportunities after it was determined that a generic system-wide approach, as is used in the Avoided Energy Supply Cost studies, conducted to help calculate benefits from the energy efficiency (EE) savings, was not feasible since at the time the diversity of DG was not in place. In addition, EE removes kWs from the system for the life of the installed measure in a passive manner, whereas DG is subject to weather related issues as well as unplanned outages, and other events. As the bulk of the 310 MWs of solar PV connected to the Company's system are 750 kW to 6 MW solar farms, the diversity if DG is still not in place. Understanding that the typical 15 kV distribution feeder can serve up to 8-10 MWs, a DG project that is a large percentage of this load becomes a contingency that the Company's engineering staffs have to plan around to maintain reliability to the other 2,500 to 4,000 customers served off the feeder.

Specific deferral locations should follow the Company's current internal guidelines for non-wires alternatives (NWA). These include:

1) The standard wires solution will likely be more than $1m – this is to provide enough deferral value to pay for a NWA;
2) The load reduction should be less than 20% of the peak load – this is to put bounds around the size of the NWA as the funding is limited by Guideline 1 above;
3) Start of construction is at least 36 months way – this is to provide enough time for customer outreach, marketing, enrollment, and construction of the NWA; and

4) The need is not based on asset or reliability condition – this is critically important as only truly growth related projects (location where the equipment is in excellent working order, but the load growth in the area has out-stripped it's capacity) is where deferral is feasible.

The use of the Navigant study can provide an approach to estimate specific locational benefit values for solar PV projects. In addition, the output of the Company's Phase II solar project is designed to value the specific benefits around true localized peak load relief (by re-orienting PV panels), the use of advanced inverters to provide voltage support (through the absorption or injection of VARs), and ride through capabilities (to provide bulk power system stability). The output of this study is specifically designed to answer many of the questions around the true benefits of distributed solar projects.

9. Other topics

Are there any major topics or perspectives related to the Task Force's scope that we have not discussed today that you would like to comment on?

A) Consumer Protection and Competitive Supply Issues with Third-party Ownership Structures

National Grid believes that due to the quantity of and desire for customer-hosted solar projects that are owned by third parties, which often involve electricity contracts, net metering contracts, and leases of real property, greater transparency about the true value provided to customers is needed. In addition, this market should be better integrated with competitive energy suppliers and the competitive retail supply market.

Because more than half of the net metering cap is reserved for net metering projects hosted by municipalities and other governmental entities, all contracts between solar developers and public entities, and the terms of those contracts (deposits, escalation factors, purchase rights and values, and other elements), should be publicly reviewed as part of this effort. This review will give the task force valuable information about the benefits that our municipalities and governmental entities are receiving from their solar installations versus what the developers are receiving, which is vital to know in order to assess how we can achieve our solar goals more cost effectively. Pursuant to G.L. c. 30B, § 1 (b)(33), energy contracts for energy or energy related services entered into by cities, towns, or political subdivisions of the Commonwealth are exempt from the typical requirements of the Massachusetts uniform procurement act, which may extend to net metering related contracts. However, such exempt contracts are required to be filed with the Department of Public Utilities, the Department of Energy Resources, and the Inspector General's office, which should provide an opportunity for public review of the contracts.

In addition, a 2012 session law expanded G.L. c. 164, s. 137, "Participation in group purchasing of electricity," among other things, to relieve municipalities and state agencies from competitive bidding requirements in granting easements, licenses, leases, etc. on real property, and to allow state entities, including the legislature, to dispose of municipal or state property by lease, easement or license when a renewable energy PPA or a net metering agreement and a group purchase is involved. Similarly, because residential net metering facilities are not subject to a cap, and virtually all such facilities are third-party owned, standard residential solar net metering contracts should be developed, regulated, and closely reviewed by state energy and consumer protection offices. In addition, solar development companies offering these solar net metering contracts to residents, business, and public entities of Massachusetts should be regulated by the Department of Public Utilities as competitive energy suppliers, and properly licensed as such.

B) Clarify Total Cost, Savings and Payments Under Current MA Policies

We believe the consultant report to the Task Force must clearly lay out the source and reality of the "bill savings" for customers that purchase net metering credits, along with the total costs and payments involved in net metering. Furthermore, the split of total payments for solar between developers and credit purchasers should be clearly explained, along with estimates of what developers need at present to develop new solar installations.

This breakdown is important because, while the total amount paid for such credits by such a customer under a PPA with a solar developer may be lower than standard rates, this cost reduction may not be guaranteed, and may not be long lasting. In addition, one customer's "savings" is an added cost for all other customers.

For example, assume each kilowatt-hour produced by a solar PV array is worth 18¢ per kWh in net metering credits, plus 30¢ per kWh in SREC II value, and that the developer signs a long-term agreement to sell the net metering credits to a town for 13¢ cents per kWh. The 18¢ per kWh in net metering credits is then applied to the town's electricity bill and the town will realize savings equal to 5¢ cents for each kWh that it purchases. Meanwhile, the project developer realizes 43¢ per kWh. However, if the project only needed 30¢ per kWh to be built and provide an acceptable return, it will realize 13¢ per kWh of additional profit. Also, the town is receiving 5¢ per kWh of "savings" from net metering, but other customers are now paying for its share of the distribution system's fixed costs. The total cost to all customers is still 48¢ per kWh, less the value of wholesale energy and any delivered energy losses.

In short, the Task Force should be provided a clear picture of the total payments by all customers for solar output, the value of bill reduction that credit purchasing customers are receiving, and the average revenue needs solar developers need today to create new solar PV facilities given current installed costs, financial structures, and return expectations.

NCLC comments re: Net Metering Task Force, consumer group discussion

Jan. 20, 2015

1. Stakeholder objectives: In discussions about net metering -- and more broadly, distributed generation and grid modernization – affordability and equity policy objectives must be valued as highly as those associated with environmental policy. Rate design, any grid modernization investment, and DG programs and policies must mitigate pre-existing regressivity in the allocation of costs and benefits of energy resource production, distribution and consumption. NCLC wants to make sure that in exchange for any costs imposed on ratepayers by net metering (see GL ch. 164, s. 139, under which ratepayers directly bear the "distribution portion of any . . . net metering credits"), those ratepayers receive equivalent or greater benefits. While I know that the terminology has become somewhat loaded, NCLC wants the process to produce some quantification of the value of the kWh that net metered customers deliver to the grid, including (to be fair to those net metered customers) the value of: avoided costs of otherwise generating the kWh; any avoided transmission or distribution investments; contributions at times of system peak; deferral or avoidance of investments in new generation plants or gas pipelines to feed those plants; and other reasonably quantifiable benefits.

We also want the Task Force process to make transparent any subsidies/supports/payments to net metered customers.

Finally, we want to make sure low-income households are able to participate as direct players in solar PV and other projects that benefit from net metering, whether through community shared solar or other means.

3. Perspectives on current net metering approach: In the absence of quantifying the value of kWh delivered under the current net metering laws and structures (see #1 above), our perspective is that net metering may pay net metered customers more than the value of the kWh delivered; but that is of course an open question. Put another way, it would be remarkably fortuitous if the value of the kWh delivered under net metering happened to be equal to the (more or less) retail price of electricity, rather than having a greater or smaller value. It is possible that the arguments for volumetric caps would be greatly diminished if some consensus could be reached about the value of kWh delivered via net metering, and the payments to those customers were commensurate with the value delivered. Caps may be an artifact of concerns, particularly on the part of utilities, that net metering unduly erodes revenues without providing sufficient system benefits.

6. Future use of net metering/minimum bill provisions: As should be clear from the above, we question the wisdom of continuing the current net metering structure in the absence of analysis showing that the value of kWh delivered via net metering is at least equal to the payments made to the net metered customer, given the provisions of GL 164 s. 139(c).

As for "minimum bills", those words can mean many things. If interpreted to mean an unavoidable customer charge imposed on all customers, and at levels much above current customer charges, we are strongly opposed to minimum bills as so defined. Because higher customer charges lead to lower kWh charges (under any fixed revenue requirement), customer charges fall most heavily on lower-consumption customers. Analysis done by my colleague John Howat shows that there is a strong correlation between low-consumption customers and low-income households, as well as African-American, Hispanic, and other minority households. Further, because higher customer charges result in lower kWh charges, this provides much less of an incentive to invest in energy efficiency or self-generation, as the cost of the avoided kWh is lower.

To the extent minimum bills would apply, in practice, mostly to customers who self-generate and therefore have unusually small bills (say, 100 kWh or less), we are neither opposed nor supportive at the present time.

8. Sector specific questions:
We are concerned that low-income households face significant hurdles in trying to participate in net metering (or other models that may result from the task Force process). Solar PV and other technologies that allow a customer to engage in net metering generally require significant up-front investment, or, if a third-party vendor is involved, a strong credit score. We would want to ensure that any policies going forward give low-income households and communities a fair chance to participate. In particular, this may require consideration of incentives and models that work for community shared solar. As is apparent

from the above, we also want there to be a clear demonstration that incentives provided via net metering (or subsequent policies) result in ratepayers as a whole getting equivalent or greater value from the kWh delivered to the grid.

As to grid modernization and TVR, NCLC has consistently raised the concern that a strong business case needs to be made before potentially massive investments are made to modernize the grid. Similar to our concerns about net metering as currently structured, we haven't seen evidence that the investments in grid mod that are being considered would yield substantial enough merits to justify the costs. We also are concerned that mandatory TVR could adversely affect low-income households, who tend to have fewer appliances and loads that can easily be shifted off of peak periods. We realize that your question asks about the potential effect of grid mod and TVR "on net metering value and framework"; we have no opinions to offer on that right now but do want to voice our general concerns about grid mod and TVR.

Submitted by Charlie Harak

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January 21, 2015

RE: Massachusetts Net Metering Task Force
Phone Focus Group F – Written Supplement

Dear Mr. Belden, Ms. Wright, and Mr. Grace,

Thank you for the opportunity to participate in Thursday's call regarding the Massachusetts Net Metering Task Force. We appreciate the opportunity to follow up on this call by providing additional comments. SRECTrade is one of the largest SREC transaction and management firms in the industry, with over 145 MW of solar assets under management.

Introduction to SRECTrade

SRECTrade facilitates the brokerage of spot and forward contract SREC transactions in the over-the-counter markets. SRECTrade's clients cover all market participants including, competitive electricity suppliers, utilities, project developers, PPA providers, leasing companies, installation firms, and individual commercial and residential system owners.

The software developed by SRECTrade allows solar owners to track their SREC generation and issuance, manage and execute transactions, and enroll facilities with state regulators. Since 2008, SRECTrade has been one of the leading sources for information regarding SREC price trends and legislative updates, bringing a wealth of knowledge and transparency to some of the fastest growing state markets in the solar industry.

We have been an active participant in the Massachusetts solar industry since the inception of the SREC program in 2010. SRECTrade was the first aggregator to register and transact SRECs from the first facilities to qualify for the SREC-I program. We facilitate transaction and management services for more than 4,100 facilities in the Commonwealth, representing more than 60 MW.

SRECTrade represents a significant and diverse group of Massachusetts businesses, residents, and investors. We have seen firsthand the value and shortcomings of the Massachusetts SREC programs that may be missed by other groups that solely focus on the sale and development of solar facilities. Our experience in the market has equipped us to be able to provide unique insight into the efficacy of aspects of the existing solar incentive program structure. Additionally, our relationship with our clients ensures that we have a long-term commitment to the owners of solar arrays because qualified facilities produce SRECs for ten years from the time that they become operational. We have made it a priority to engage our customers with a transparent platform, creating an environment where the residents of the Commonwealth can feel involved and knowledgeable about the SREC market and the return on their investment in solar. We stand alongside many residents of the Commonwealth, sharing a common desire and eagerness to help Massachusetts achieve its full potential with renewable energy.

Interrogatories & Comments

1. Stakeholder Objectives and Priorities from the Task Force Process

Over the past four and a half years, Massachusetts has seen immense success and impressive growth in the deployment of Solar PV. This growth is a testament to the Commonwealth's RPS program and successful incentive programs, including SREC I and SREC II, The Green Communities Act, and other incentive and rebate programs. Unlike other efforts for alternative energy integration, such as the controversial, and now stalled, Cape Wind project, the policies supporting the solar market have proven to be seamless and productive—meeting and exceeding program targets and goals. Massachusetts' solar policies set the stage for Massachusetts to become the national leader in solar that it is today, but it is vital that Massachusetts continue to promote and implement solar policies that bolster the Commonwealth's renewable energy future. Accordingly, we would encourage the Task Force to focus on improving existing policies, rather than disrupting the market with an abrupt policy change.

2. Long-term Massachusetts Solar Market Goals

In an effort to maximize the benefits of solar while minimizing costs, we encourage the Task Force to focus on the following goals:

1. **Maintain the SREC II Program.** The Massachusetts SREC I and SREC II programs have proven that market participants have been able to thrive under the existing framework, and the industry has built a successful infrastructure to continue to leverage more growth. The programs were carefully designed to minimize costs while maximizing growth, job creation, and market stability. A shift in policy away from the SREC incentive would create instability and invite uncertainty in the market, triggering a disruption in the market. In the interest of encouraging continued growth, we believe it is in the best interest of the Commonwealth to work to improve, rather than to replace, the successful SREC program.

2. **Lift the net metering caps.** Net metering caps have proven to be relatively unproductive policy mandates—constantly requiring review and reconsideration by the Legislature, when resources could be better spent focusing on improving the existing program. With forecasts projecting that the existing net metering caps will be reached within the first half of 2015, it is of paramount importance that the Task Force encourages the lifting of the net metering caps. Eliminating this barrier will allow Massachusetts to continue on its path of booming solar success.

3. **Prioritize distributed generation to increase grid reliability and resiliency.** Equitable access to solar will maximize growth and provide the best opportunity for the Commonwealth to increase grid reliability and resiliency. Accordingly, we encourage the Net Metering Task Force to carefully consider opportunities to expand access to solar to those limited to the use of virtual net metering and to those in low-income communities. This goal would include taking into consideration the preservation of virtual net metering for community solar projects, the establishment of financing programs for low-income communities, and the overall rate redesign for Massachusetts ratepayers. By focusing on these issues, Massachusetts can maximize its growth potential and continue to add reliability and resiliency to its grid.

3. Perspectives on Current Net Metering Approach

Please see the response to Question 2, Point 2.

4. Perspectives on Current Massachusetts Solar Incentive Model Approach

With respect to its incentive structure, the Commonwealth of Massachusetts is in a unique position because it can utilize its deregulated electricity supply structure to continue to foster a competitive market for both traditional and renewable electricity. Continued use of the existing REC and SREC markets is the clear path to fostering the most competitive market for all stakeholders in the incentive program. This includes solar developers and system owners, competitive electricity suppliers, and the Massachusetts ratepayer. The market minimizes costs while maximizing growth, job creation, and market stability.

In less than four and a half years, the Solar Carve-Out Program (SREC I) helped to incentivize the development of 654.7 MW of qualified capacity across 11,787 qualified projects (as of 1/12/2015).[1] In 2013, Massachusetts was ranked 4th in annual installed solar capacity (237 MW installed in 2013) and 5th in cumulative installed capacity (678 MW cumulative).[2] The 2014 Massachusetts Clean Energy Industry Report states that "Solar Deployment is Creating Thousands of New Jobs in Massachusetts, Half of All Renewable Energy Jobs Statewide," with nearly 60% of the state's 21,000 renewable energy jobs related to the solar industry.[3] And according to a recent report titled, "A Survey of State-Level Cost and Benefit Estimates of Renewable Portfolio Standards," issued by the National

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[1] *See* RPS Solar Carve-Out Qualified Renewable Generation Units, available at http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/solar/rps-solar-carve-out/current-status-of-the-rps-solar-carve-out-program.html.
[2] *See* http://www.seia.org/state-solar-policy/massachusetts.
[3] *See* http://images.masscec.com/reports/Executive%20Summary.pdf.

Renewable Energy Laboratory (NREL) and the Lawrence Berkeley National Laboratory, compliance costs for the state of Massachusetts in 2012 equaled $111 million compared to benefits of $328 million, representing a net benefit of $217 million under the current Renewable Portfolio Standard incentive program.[4]

In addition to its economic successes, the SREC program offers inherent ratepayer protection with its flexible incentive pricing. SREC prices adapt as supply, demand and market dynamics shift. Furthermore, the SREC II program introduced even more flexibility to the program by requiring the Department of Energy Resources (DOER) to review the SREC II Factor Guideline by March 31, 2016. This review will allow the DOER to reduce the SREC II Factors to lower the overall costs of the program to ratepayers if market conditions permit it.[5] Finally, the design of the program allows a facility to revert to producing Class 1 RECs after its forty quarters/ten years of eligibility in producing SRECs under SREC I and SREC II have expired. This creates continuity and predictability in the market that would not be available, for example, with a declining block incentive model. Carefully contemplated and calculated programs like SREC II also create confidence in the marketplace, which is a fundamental element in ratepayer protection, and one that should not be overlooked. The current successes were achieved over the course of several years of stakeholder time, capital, and intellectual effort, and the flexible yet reliable market should continue to be employed by the Commonwealth.

Understandably, as with any market, there are always areas to fine-tune. In its task to review the current incentive program, we would encourage the Task Force to consider the following topics to improve upon an already-successful program:

- Improving SREC market liquidity and long-term contract opportunities;
- Minimizing costs to ratepayers through stable pricing, while providing the appropriate level of incentive to solar project owners;
- Increasing market transparency with clearly published supply and demand information, as well as pricing data; and
- Encouraging competition among electricity suppliers, not only to facilitate cost-reduction pressure, but to make the market as open and accessible as possible.

Given our experience in the market, we welcome the opportunity to discuss these topics with the Task Force further, and are happy to answer any questions that the Task Force may have for us.

5. Perspectives on Other Solar Incentive Models

SRECTrade is an active participant in all SREC markets. Additionally, SRECTrade administered the competitive procurement process for SREC Delaware ("SRECDE") for two years, an experience which presented its own shortfalls and administrative costs. For competitive procurements in particular, the administrative cost is high and the incentive for improvement is low. Competitive procurements present their own legal, administrative, and soft costs, and include an added upfront burden of soliciting and selecting a program administrator. A central aspect of competitive procurement programs like SRECDE is the lack of natural competition. In administratively run and controlled programs, there is no competition-driven incentive for improvement; in contrast, there is natural competition in market-based mechanism such as the Massachusetts SREC program, which encourages stakeholders to improve services in an effort to capture greater market shares.

While many other incentive programs exist, it is important to give gravity to the program that has proven to be extremely successful in Massachusetts—the SREC program. The success of the program is supported by increased solar installations at a lower price per watt,[6] growth in the renewable energy job industry,[7] and a program that can

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[4] *See* http://www.nrel.gov/docs/fy14osti/61042.pdf.
[5] *See* 225 C.M.R. 14.05(9)(I)(3).
[6] *See* http://www.mass.gov/eea/docs/doer/renewables/installed-solar.pdf; *See also*, U.S. Solar Market Insight: 2010 Year-In-Review, Full Report, SEIA and GTM Research, 2010.
[7] 2014 Clean Energy Industry Report: Executive Summary, *available at* http://images.masscec.com/reports/Executive%20Summary.pdf; 2013 Clean Energy Industry Report, *available at* http://www.masscec.com/content/2013-clean-energy-industry-report; 2012 Clean Energy Industry

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adjust to changing supply and demand dynamics by taking into consideration installation costs, electricity rates, and other available incentives.[8]

6. Perspectives on Future Use of Net Metering, as well as Minimum Bill Provisions

As previously discussed, we encourage the Net Metering Task Force to carefully consider opportunities to expand access to solar to those limited to the use of virtual net metering and to those in low-income communities. Virtual net metering presents a variety of problems in capacity markets and with kilowatt restrictions in incentive programs, and these limitations must be addressed. To address these issues, we would encourage the Task Force to look to other markets that have been successful in using net metering and decoupling to its ratepayers' and regulated utilities' benefits.

When taking into consideration whether a minimum bill should be part of overall rate redesign, it is critical that the Net Metering Task Force weigh the benefits that distributed generation facilities are providing to the grid, including grid reliability, resiliency, and reduced demand during peak periods.

7. Perspectives on Policy Transitions

Instability and insecurity are the hallmarks of failed incentive programs. States that are constantly shifting gears and making drastic policy transitions create uncertainty in the market, which can result in unintended consequences such as increases in financing costs. This can result in fewer projects being financed and ultimately a decline in renewable energy jobs and industry growth.

On the other hand, improving existing programs promotes stability and confidence in the market, encouraging investment by stakeholders across the industry. Of the two paths, the choice seems clear: to follow the path that will continue to make Massachusetts a leader in solar.

Thank you for your consideration in this matter.

Best Regards,

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Report, *available at* http://www.masscec.com/content/2012-clean-energy-industry-report; and 2011 Clean Energy Industry Report, *available at* http://www.masscec.com/content/2011-massachusetts-clean-energy-industry-report.

[8] See, et al., Figure 2-16: Massachusetts PV Installations and SREC Prices, 2010-2011, U.S. Solar Market Insight: 2011 Year-In-Review, Full Report, SEIA and GTM Research, 2011.

Net Metering Task Force - Focus Group Interview
Northeast Utilities Answers
January 23, 2015

1. *What are your goals and objectives for the task force? Of those, what is your most important objective and why? To the extent that goals or objectives may conflict, how would you prioritize?*

NU supports MA clean energy goals and is committed to help the State meet those goals. However NU is concerned about the costs associated with reaching these goals, specifically the solar goal. NU believes that MA should focus not only on a volumetric goal (i.e., 1,600 MW), but it should also develop a cost-effectiveness goal (i.e., all-in cost per kwh of solar installed) in order to ensure that the volumetric goal is accomplished without the use of significant level of incentives. In order to move forward, the State should learn from other jurisdictions that have been able to increase the share of renewables and solar, but in a much more cost-effective manner.

MA's incentive structure for solar relies on two mechanisms that need to be reexamined and adjusted in order to meet NU's proposed cost-effectiveness goal: 1) net metering credits and 2) Solar Renewable Energy Credits (SRECs). These financial incentives are paid for by all customers, regardless of whether their homes or businesses are interconnected to solar distributed generation facilities.

Similar billion dollar investments in clean energy could reap more benefits if done in a balanced and strategic way. NU believes a more balanced approach is needed to meet the state's solar goals to ensure that 1) MA's customers are not paying above-market prices for energy; 2) there is rate fairness among customer groups and 3) there is transparency in the level of incentives provided to solar or any other renewable resource.

2. *The current stated goal of the Massachusetts solar policies is to reach 1,600 MW of installed solar capacity in the 2020 timeframe. Please discuss your perspective on this MW goal, its timing, and the appropriate objectives for the state solar market beyond the timing and quantity of this goal.*

NU's analysis indicates that Massachusetts is currently investing in solar power at well above market prices. Solar power with MA's incentives has been priced 6-8 times higher than conventional wholesale power and 3-5 times more than conventional wholesale renewable power over the past several years (see table below). MA's solar incentives are 3 times as high as those provided in CT through a competitive program. Given current trajectory, over the next 15 years MA customers will pay a projected $7 billion in above market costs just for solar power. NU contends that the State needs to analyze whether this level of investment is warranted and believes there are better mechanisms to achieve similar solar goals, at a much lower cost.

Net Metering Task Force - Focus Group Interview
Northeast Utilities Answers
January 23, 2015

Illustrative MA Solar Net Metering Costs (c/kWh)						
	2010	**2011**	**2012**	**2013**	**2014**	**2015**
Net Metering Rate Components						
Energy	8.4	7.5	7.3	7.3	9.4	10.9
Transmission	2.3	2.3	2.3	2.3	2.3	2.3
Distribution	5.3	5.3	5.3	5.3	5.4	5.5
Total Net Metering Value	*16.1*	*15.2*	*15.0*	*14.9*	*17.1*	*18.8*
Avg. SREC I Market Price	*58.6*	*52.9*	*29.2*	*25.0*	*29.0*	*43.5*
Total Solar Payment	**74.7**	**68.1**	**44.2**	**39.9**	**46.1**	**62.3**
Avg. Wholesale Energy Price	5.0	4.7	3.6	5.6	6.9	7.0
Avg. Class I REC Price	2.5	2.0	5.7	6.5	5.5	5.5

3. *Solar PV systems in Massachusetts typically benefit from net metering with various system sizes and configurations receiving different net metering benefits. Additionally, volumetric caps to net metering have been revised through legislation on multiple occasions over the past several years. Please provide your perspective on the current Massachusetts net metering approach.*

NU believes the existing net metering approach is not well designed to support increased deployment of distributed generation and solar in an efficient, cost effective and sustainable manner. Net metering was put in place many years ago and did not contemplate the level of deployment currently being planned for. Specifically NU wishes to highlight the following:

- T&D services are supported by largely fixed costs driven by customer and maximum demand, and not by energy usage.
- Through net metering, DG customers are avoiding paying for some or all of these T&D services (resiliency, maintenance of grid), yet receiving even more value from the grid (reliability, start-up services, ability to transact and monetize solar energy).
- These costs that DG customers are being credited for, even though they are being incurred to operate and maintain the grid for their use, must still be collected by the electric utility company and are increasing the costs to non-DER customer bills.
- Further, DG customers are avoiding other non-T&D costs and shifting cost recovery to non-DG customer bills. For example:
  - o Renewable Fund ($12M total cost for NSTAR and WMECO)
  - o C&LM/Energy Efficiency Fund ($234M total cost for NSTAR and WMECO)
  - o Reconciling rates for Company and public policy programs (e.g. pension, attorney general consulting, net metering, storm costs, basic service reconciliation, low income and transition ($105M total cost for NSTAR and WMECO)

Furthermore, virtual net metering (VNM) has created a significant cross subsidy mechanism and administrative burden. VNM's specific issues include:

- Transfer of payments from generator to customer accounts has no relation to actual load reductions. It is a pure financial transaction that has no relationship whatsoever with the actual generation and use of energy.
- Host and customer accounts are unrelated resulting in imbalances between credits and customer bills with some customers creating significant credit balances.
- Settlement requirements for net metering customers with DG greater than 60 kW are an administrative burden and results in conflicts with ISO rules
    - State rules require net metering units up to 10 MW to be registered as settlement only generators (SOGs) when ISO-NE does not recognize SOGs at 5 MW and greater
    - DG owners who bid capacity into the FCM market are "double dipping" because capacity payments are part of the basic service price that they receive credit for
    - Utilities should be allowed to treat all net metering resources as load reducers which would eliminate ISO conflicts
- Community solar garden operators are essentially retail energy suppliers that are offering green products to customers, but they are not subject to the same licensing requirements as competitive retail suppliers nor are they purchasing power through the ISO-NE market as do other suppliers.
- Billing is largely manual as costs recovery for implementation has not been granted. In addition manual bills are growing at an unsustainable pace.
- Customers are confused by virtual net metering transfers as they struggle to match credits with host bills.
- Hosts are not billed on the appropriate rates as they take service based on parasitic load rather than capacity of the unit. Larger generators should be assigned large commercial rates; this results in improper cost allocation.

The current net metering approach relies on an artificial construct that does not reflect actual power flows. For customers with bi-directional or interval metering, It involves taking the difference between energy measured on an import channel and an export channel of a customer meter. The effect is to replicate a single register meter that "spins backwards", but this has no logic when generation and delivery is measured on distinct channels.

- When energy is metered on separate channels (as is currently the case for any unit greater than 60 kW), there is no need to subtract channels. The export channel reflects total energy exported after serving load.
- The netting process creates a mismatch between billed retail energy and actual metered wholesale energy for interval metered customers. Net metering customers often times report zero load as a result of the netting procedure when, in fact, they have real load obligations that are picked up by suppliers. These costs are ultimately recovered from all customers through a reconciliation of costs for both Basic Service and alternate supply.

Ultimately as explained further, NU believes the existing net metering and virtual net metering system needs to be replaced with a new rate design that more properly recognizes today's environment and ensures the principle of rate equity.

4. *Massachusetts solar installations typically benefit from a range of incentives, including SRECs, federal tax credits and net metering being major contributors to system economics. Please discuss your perspective on the current mix of incentives other than net metering (and virtual net metering) available to Massachusetts solar systems with a particular focus on the Massachusetts SREC incentive.*

The RPS Class I Solar Carve-Out has been very good at supporting the development of solar resources, but NU is concerned that this is mostly due to the availability of customer-funded SREC revenues that ultimately far exceeded what was is necessary to support solar development in the state. The observation of lower prices in other states and need to expand SREC I beyond 400 MW due to rapid development both suggest this.

NU appreciates the benefits of providing price certainty through incentive programs, but think prices should be set through a competitive and transparent process vs. having an administrative process set artificial "floor prices". Observation of programs in CT and RI shows this allows all customers to get the same benefits of solar power at much lower cost. NU has also observed that the complicated Solar Carve-Out design has produced many unanticipated and undesirable outcomes, prompting DOER to intervene and modify regulations several times. NU consequently encourages future policies to be simplified and to avoid reliance on DOER to serve as "market-manager".

NU also believes that any incentives to be distributed should be capped or at least an annual budget amount should be put in place in order to control the total costs of the program.

NU is also not convinced that a mature industry couldn't be sustained through a RPS program without price supports. Sophisticated participants can adequately assess and manage SREC price risk if they have adequate information, reliable regulations and tools to manage volatility (flexible banking, some long-term contract support, etc.). The NJ SREC program has sustained development over the past couple years (~200 MW/yr in 2013 and 2014) with these features despite not having a price floor mechanism and having experienced substantial volatility in the past.

Finally, it is worth comparing the development of the solar industry with that of the energy efficiency industry. In energy efficiency, incentives and rebates are introduced only at the early stages of development, but the primary goal is to phase-out those incentives over time and let the market forces do their work. NU believes it is important to develop an incentive model that has a similar goal in mind and aims to be phased-out over time as market dynamics take a hold of solar deployments.

5. *Other states have implemented a range of incentive program types in order to grow their solar markets. Several program types that you may be aware of include (but are not limited to):*
    - *Standard offer incentive programs (aka. feed-in tariffs)*

- *Declining block incentive programs*
- *Competitiveprocurements (aka. auctions or solicitations)*

There are also many variations on these approaches, as well as co-policies.

Are any of these incentive program types of particular interest to you? Please discuss your impressions of these or other incentive program types that you may be aware of, and whether we should focus on particular incentive types that are of interest to you. How do you think the effectiveness of these incentive program types vary for different solar installation types (e.g. residential vs. utility scale)? What options would you like to see the consulting team consider and analyze for Massachusetts?

NU believes that to the extent state policymakers determine there is a need to provide additional incentives to solar, such incentives should be fair, transparent, appropriate and should be fairly distributed among the customers in the State. Some of our key policy recommendations around incentive structure include:

- DG and solar should only be compensated for benefits that are known, measurable and verifiable and that presently reduce utility cost of service to customers, not on a subjective 'value' to society.
- Incentives should be periodically re-evaluated based on market conditions. Once underlying policy objectives are met or as DG technologies become more cost competitive (or cost prohibitive), such incentives should be modified or discontinued.
- Externalities (job increases, economic benefits, environmental benefits) should be treated consistently for all customers and resource types – for example, there is no difference between utility scale and distributed solar.
- Any solar incentives above the wholesale price of power should be regulated by the DPU.
- Any incentives associated with perceived T&D benefits, should only be provided as part of changes to distribution business models that allow those benefits to be captured and priced.

NU has evaluated and is supportive of models that better provide transparency and drive lower costs to customers. NU has been pleased with the results of long-term contract and tariff programs in CT and RI and would be supportive of a similar, thoughtfully designed program in Massachusetts with the following features:

- Transparent prices set according to a competitive bidding process
- Minimal differentiation between project/customer classes. Policy makers should not insist on supporting higher-cost project types at the exclusion of lower cost alternatives that can provide similar benefits to the system as a whole.
- A tariff design would likely streamline administration and payments and be preferable to entering into a substantial number of long-term contracts.

- NU appreciates the challenge of developing projects when subject to a procurement schedule, so would entertain a Declining Block Design provided Block Pricing was based on transparent analysis and subject to DPU approval.
  - NU also recommend that blocks be priced on a schedule that would end at zero, ensuring that no further programs would be required to sustain solar industry until it was competitive with other resources.
- NU also recognizes that long-term, fixed-price EDC commitments allocate market risk to customers and may be inconsistent with important market-design and restructuring goals. If a Solar RPS is retained for these reasons, the company would recommend it be substantially simplified and not include any price support mechanisms.

6. *During the past year, efforts have been made to revise the framework for net metering in Massachusetts including the addition of a minimum bill for all electricity ratepayers. Please discuss your perspective on the future use of net metering/virtual in Massachusetts and, to the extent you are able, what options or changes would you like to see and why?*

NU believes that policies and regulations related to distributed generation and solar should balance the following objectives:

- Minimize customer bill impacts
- Achieve federal and state energy, environmental and economic policies and goals
- Protect the interests of non-participating customers
- Facilitate customer choice
- Recognize the appropriate costs and benefits of distributed solar technologies
- Acknowledge federal and state energy, environmental and economic policies
- Recover prudent costs of integrated grid services

The Department's long-standing rate design goals are efficiency, simplicity, continuity and fairness:

- Efficiency means that the rate structure should reflect the cost of providing distribution service and provide an accurate basis for consumer decisions;
- Simplicity means that the rate structure should be easily understood;
- Continuity means that rate structure changes should be made in a predictable and gradual manner;
- Fairness means that the rate structure should require no class of customer to pay more than the cost of serving that rate class;

Net metering as it currently stands violates these principles. Proper cost allocation is essential to fair ratemaking and the avoidance of hidden cross-subsidies. Any required allocation of costs to others should be fair, rational and transparent. In order to ensure that net metering or other mechanisms do not result in cost displacement among customers or impose undue costs on all non-distributed generation ratepayers, regulators must ensure that rates reflect equitably the benefits and costs of distributed generation. Deviations from this policy lead to distorted incentives and diseconomies that are not sustainable over time.

NU believes the time is right to implement a new rate design that disaggregates the different elements associated with distributed generation operations and believes this move is essential to further support the deployment of these resources.

- NU proposes to implement new and/or leverage existing measurement technologies, to capture three essential data points associated with distributed generation operations:
    - Power exported to NU at the point of receipt
    - Power delivered to the Customer at the point of delivery
    - Production at the Customer's DG facility

- NU also further recommends a rate design that:
    - Recovers fixed T&D costs for a distributed generation customer at a level consistent with similar non-DG customers
    - Compensates for the energy exported to grid based on the market value of solar in the Massachusetts market
        - One option is to compensate power that meets host load at retail prices, and any excess would be paid at wholesale rates (i.e., P2 rate at NSTAR)
        - Another alternative is to develop some type of value of solar or feed-in tariff methodology
    - Provides additional incentives in a separate transaction if the State so chooses.

- Other alternatives NU wishes to highlight include:
    - Developing a new customer class for distributed generation customers that have capacity or demand charges (not subject to net metering credits) that recover the fixed costs that are being displaced.
    - Higher fixed customer charges and/or demand charges for all customers would also mitigate the cross subsidization issue between customers with and without DER.

In order to move forward, NU's bottom line recommendation is the establishment of a formal regulatory proceeding that can determine appropriate changes to rate design and proper valuation of DER resources where all parties can bring sworn testimony, facts and data to support their positions. The regulatory bodies are established for that precise purpose and should be the proper avenue to develop the long-term changes needed to ensure all State goals are met. Such a proceeding would:

- Determine the quantifiable impact that DER have on the cost to serve electric customers inclusive of:
    - Cost of the distribution system necessary to serve electric customers where DER is not available
    - Cost to serve electric customers who do not receive service from DER

- Consider whether the existing rate design (inclusive of net metering) would fairly and reasonably allocate costs and benefits to DER and non-DER customers
- Determine the impact that DER may have on the equitable collection of reconciling charges on a volumetric basis
- Evaluate other rate design alternatives that might more properly allocate costs and benefits of DER

7. *A. At the 2nd Task Force meeting, it was suggested that analysis should account for uncertainty costs, (i.e., transition costs due to changing goals and programs.) Please discuss qualitatively the nature of these costs as you see them, and whether and how you might suggest such costs could or should be quantified.*

   B. Are there particular threshold milestones where it might make sense to consider policy transitions in order to minimize such costs? What other means are available to minimize such costs?

It is unclear what types of costs are being referenced here. Marketplace is full of uncertainties. Changes to programs occur multiple times and at different places. Any new program being developed should always take into account impact to existing programs to ensure a smooth transition. In addition, any transition costs are outweighed by the above market costs MA is paying to support the deployment of solar.

8. *How would you propose a minimum bill calculation methodology be applied? What other models would you point to that are viable for achieving your objectives?*

NU believes that any minimum bill calculation should be based on higher fixed charges based on the utility's approved embedded cost of service study which functionalizes cost into customer and demand components. NU also believes that minimum bill provisions should be applied to all customers and not restricted to a particular class. Ultimately, NU finds that a minimum bill concept cannot work without proper rate design as presented in answer to question # 6 above.

NU is providing additional information on the minimum bill under a separate attachment.

With respect to FCM revenues for current Class II and III systems, for which utilities secure certain rights under net metering tariffs, please describe your current practices, and future plans.

NU has not offered capacity associated with independent solar facilities into the Forward Capacity Auction. The Company isn't comfortable assuming a capacity obligation associated with a resource it ultimately doesn't control.

Solar resources not offered into the FCM still provide capacity benefits by reducing load and lowering capacity load obligations.

Are utility system integration costs for solar projects now fully borne by project owners?

It is important to note that simplified DG applicants, which are the vast majority of projects at NU, pay no fees to process applications so any costs and effort that the Companies incur to process these applications are not directly recovered by the DG applicants, but recovered from all ratepayers.

In addition, there is no full tracking of DG integration costs (like what NU does for energy efficiency) so there are elements such as customer education, tracking and reporting that are not paid for by DG project owners, but recovered in general rates. It is worth mentioning that with historic test years in Massachusetts and exponentially increasing application volumes, there are real challenges to staffing appropriately for this type of work.

Also ongoing O&M is not currently recovered from project owners. This includes ongoing maintenance of equipment installed solely for DG customers; increase in work for dispatch and account representative to manage planned and unplanned outages; mapping of DG in GIS; regulatory activity, response to customer inquiries when projects go off-line (e.g. transfer trip phone line issues); and training for field workers on DG safety.

What are the expected potential impacts of Grid Modernization/Time-Varying Rates efforts on net metering value and framework?

This is difficult to assess without further information regarding how Grid Modernization and Time Varying Rates will be implemented.

What are your experiences in other state solar markets with alternative incentive models or policies in place?

See above answer to #5.

Please describe your past and expected future participation in SREC floor price auctions.

The company has not yet purchased re-minted auction certificates. The Company purchases energy and RECs to serve Basic Service on a short-term basis (less than 1-year) and re-minted auction certificates have not historically been the lowest cost option to meet short-term requirements. The company would likely seek to purchase re-minted certificates in the future if they were the least cost option for short-term compliance.

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Northeast Utilities Answers
January 23, 2015

9. *Are there any major topics or perspectives related to the Task Force's scope that we have not discussed today that you would like to comment on?*

One major area that has not been asked, but we think it is important to reflect in the final report is the value that the grid provides to DG resources. It is important to note that the benefits of DG systems increase with the level of utility involvement in their deployment – location, size and dispatchability are critical. The grid provides many valuable services to all customers whether they have a DER behind the meter or they do not have DER. Ultimately, it would be very expensive to replicate the reliability that the grid provides to DER customers on a stand-alone basis.

Here are the key operational areas of value that the grid provides to all customers:

- Reliability - Provides power when DER fails and compensates for variable output of DER.
- Frequency regulation- Through instantaneously balancing supply and demand, grid provides electricity at a consistent frequency.
- Real and Reactive Power Balancing - Balancing extends beyond real power, as the grid also ensures the amount of reactive power in the system balances load requirements and ensures proper system operation.
- Redundancy - With the grid redundant capacity can be polled among multiple customers, rather than each customer having to provide its own backup resources.
- Start-up power - Grid provides instantaneous power for appliances and devices such as compressors, A/C, transformers, welders that require a strong flow of current when starting-up. An A/C using just PV to start-up won't able to do so, unless it is oversized to handle this in-rush current.
- Voltage regulation/quality & harmonic distortion - Grid allows customers to experience voltage levels within narrow bands with little harmonic distortions. Voltage from a DG installation that is not connected to the grid experiences higher voltage harmonic distortion which can damage sensitive consumer end-devices. Harmonics cause heating in many components, which can reduce the life of the equipment.
- Efficiency - Grid connectivity allows rotating-engine based generators to operate at optimum efficiency which is operating steadily near full output. A distributed energy resource, not connected to the grid, would have to match load on an instantaneous basis limiting the option to run at close to full output, reducing efficiency by as much as 10-20%.
- Energy transaction - Grid provides the ability to install any size DG that they want. Utility connection allows the consumers to transact energy with the utility grid, getting energy when customer needs and sending energy back when the customer is producing.

These services need to be valued as part of any cost/benefit analysis. Attached to this response we are providing a copy of EPRI's Integrated Grid paper that summarizes the elements above.